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Bulk Electric Power Systems: Operations and Transmission Planning

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Chapter 23. Utility System Planning

Utility system planning is a complex process that starts with projection or forecasting of demand for electricity and develops alternative scenarios for the adequacy of generation resources and necessary transmission and distribution system additions. This endeavor is especially complex because the lives of the components and subsystems often exceed 40 years.

The roles and responsibilities for planning the future grid have evolved over the decades, and they continue to change. Prior to industry restructuring in the 1990s, planning for future infrastructure investments was largely in the hands of the vertically integrated, investor-owned utilities that planned both generation and the delivery system with cooperation among neighbors through the then-existing power pools or the large federal utility entities in the West and the Tennessee Valley Authority in the East (Stoll 1989, Balu et al. 1991).

The Energy Policy Act of 1992 (EPACT 1992) required open access to transmission and created a new class of generators called exempt wholesale generators. Behind these changes was the intent to open competition in the electricity sector and permit wholesale customers to buy in a competitive open market. FERC Orders 888 and 889 issued in 1996 started the regulatory implementation of the EPACT 1992, and significant restructuring of the industry resulted. Order 888 fundamentally changed the dominant business model of the investor-owned utility industry by unbundling transmission services from the sale or marketing of electricity.

With these changes, the integrated utility planning process was fundamentally changed. The following decade saw a significant decline in transmission investment Orders 888 and 889 created challenges to coordination of transmission and generation planning. Coordinated planning of transmission expansion and generation was the standard within the vertically integrated utility prior to restructuring, and was generally precluded by Order 888 as a consequence of the resulting separation of transmission from generation in many regions (Hirst and Kirby 2001).

The Energy Policy Act of 1992 and the diverse industry response across the various regions within the United States increased the diversity and complexity of utility planning. Where wholesale markets and independent power producers are significant, the responsibility for transmission planning largely rests with the RTO/ISO as does the procurement of generation resources. Where vertically integrated utilities continue, the process is still more complicated due to the existence of exempt wholesale generators, open transmission access, and the FERC orders.

Using funds from the American Recovery and Reinvestment Act of 2009 (Recovery Act), the U.S. Department of Energy has initiated coordinated, interconnection-wide transmission planning, with broad stakeholder input, and processes to feed these transmission plans back into decision-making at all levels (Funding Opportunity Announcement, FOA #68).[9] This interconnection-wide planning activity is meant to facilitate development of robust transmission

[9] The America Recovery and Reinvestment Act of 2009 directed the U.S. Department of Energy to provide assistance for the development of interconnection-wide transmission plans for the Eastern and Western Interconnections, and for Texas (ERCOT).

networks that can enable the use of new, clean energy generation and address the weaknesses that exist in the grid.

In 2011, FERC issued Order 1000, Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities, a continuation of Orders 888 and 890. This new order contains guiding language regarding how transmission planning cost allocation should occur.[10] This order is expected to result in greater emphasis on coordination of generation and transmission planning and more cooperation among neighboring utilities.

A well-planned regional or interregional transmission system has many economic and reliability benefits, which include but are not limited to improving load diversity, providing access to lower-cost remote generation, diversifying the resources portfolio (capacity and energy), sharing of resources and reserves among neighbors, enabling development of new resources and their integration, mitigating market power, and reducing price volatility. Reliability benefits include reduction of outages from multiple system contingencies and sharing of reserves, both of which also provide economic benefits. Transmission provides these benefits while accounting for less than 10% of the final delivered cost of electricity [total electricity retail sales revenue was $372 billion in 2011 (EIA n.d.)]. In general, three transmission expansion-planning approaches are in use:

1. Plan incremental transmission and generation additions to ensure system reliability
2. Plan incremental transmission and generation additions to ensure reliability and relieve system congestion or constraints and improve economics
3. Plan a transmission "overlay" that would realize the broad benefits discussed in addition to allowing remote resources to reach all energy markets—without adversely affecting underlying AC transmission systems through appropriate upgrades.

The first two approaches generally look out 10 years or fewer. Many transmission organizations refer to their 10-year plans as "long-term" and adjust these "long-term" plans with "near- or short-term" plans to account for recent system changes. These plans typically study incremental transmission additions, new generation, and load growth projections to address reliability and, in some cases, how to mitigate transmission system constraints and allow more economic operation.[11] The adoption of the third approach, which generally looks out 15 years to more than 20 years, is a recent trend among utilities in transmission planning and signals a return to the longer-term planning that was common before restructuring. The benefit of this approach is that long-term needs of the transmission system, in terms of capacity and corridor requirements, can be identified by analyzing various scenarios and identifying common transmission needs in a proactive approach. This information can then be used in subsequent feasibility and detailed system studies that address reliability concerns, transmission system constraints, access to lowest-cost generation resources, and impacts to underlying systems. A combination of these three approaches is best employed to address the particular needs of the system being studied. A bottoms-up approach can address short-term reliability and constraint mitigation needs, and a

[10] For the complete Order 1000 text, see http://www.ferc.gov/whats-new/comm-meet/2011/072111/E-6.pdf.
[11] Constraints (also referred to as *congestion*) are a condition of the transmission system in which the transmission line loading has met the operating limit criteria for which it was designed. It is a problem to the extent that lower-cost resources are prevented from reaching higher-priced markets.

top-down, "value-based"[12] approach might best address the system's long-term reliability and economic needs.

Short-term studies may work well in some applications, but they may not adequately identify the longer-term (20-year and beyond) needs of the transmission system. Reliance on the short-term approach may lead to sub-optimization of the bulk electric system over time (e.g., inadequate transmission capacity and voltage selected). For example, in the short term, a lower-voltage and less expensive line addition may be adequate but may require an expensive upgrade within a decade; in contrast, an initially more expensive and higher-capacity line might be less expensive in the long term. Short study periods and their potential sub-optimization—given the 40–60-year (or more, in many cases) in-service life of transmission lines—may limit the possibility of constructing higher-efficiency multiple-line systems and identifying underlying system upgrades to fully realize the reliability and economic benefits a robust transmission system provides.

As states and federal agencies work to implement new energy policies, the process of utility planning will continue to change and evolve. New and emerging technologies discussed in Section 26.1 offer new technical solutions, and new institutional arrangements may facilitate their adoption. Barriers to institutional innovation may also bar adoption of new technological solutions. The cooperation being promoted by the interconnection-wide planning activities of the Recovery Act as well as the new FERC Order 1000 may be critical elements to utility planning.

[12] A value-based approach seeks to quantify the cost of outages and balance it with the cost of infrastructure to avoid or minimize the costs of outages to customers. [13] All planning must meet NERC standards as shown on its website at http://www.nerc.com/page.php?cid=2|20.